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January 20, 2000

Mr. William Grimley
Emission Measurement Center (MD-19)
U.S. Environmental Protection Agency
Research Triangle Park, North Carolina 27711


Attn: Electric Utility Steam Generating 1
Unit Mercury Unit Test Program

Dear Mr. Grimley:

Enclosed are two (2) copies of the Stack Test Report for the Speciated Mercury Emissions Testing at the Basin Electric Power Cooperative Antelope Valley Station Unit 1.

If you have any questions or comments as to the contents of this test report please contact me.

Sincerely,


Jerry Menge
Air Quality Program Coordinator

jm:mev

cc: Dana Mount, ND State Health Department w/encl.



**SPECIATED MERCURY
EMISSIONS TESTING**

Performed For
BASIN ELECTRIC POWER COMPANY

At The
**Antelope Valley Station
AVS Unit B1
Beulah, North Dakota**

Test Date
July 13 and 14, 1999



Mostardi Platt

A Full-Service
Environmental Consulting
Company

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DATE SUBMITTED: JANUARY 5, 2000

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1.0 INTRODUCTION

1.1 SUMMARY OF TEST PROGRAM

The U.S. Environmental Protection Agency (EPA), is using its authority under section 114 of the Clean Air Act, as amended, to require that all coal-fired utility steam generating units provide certain information that will allow the EPA to calculate the annual mercury emissions from each unit. This information will assist the EPA Administrator in determining whether it is appropriate and necessary to regulate emissions of Hazardous Air Pollutants (HAPs) from electric utility steam generating units. The Emission Measurement Branch (EMB) of the Office of Air Quality Planning and Standards (OAQPS) oversees the emission measurement activities. Braun Intertec Corporation (Braun Intertec) conducted the emission measurements.

EPA selected the Basin Electric Power Cooperative (BEPC) Antelope Valley Station (AVS) in Beulah, North Dakota to be one of seventy eight coal-fired utility steam generating units to conduct emissions measurements. Testing was performed at AVS Unit B1 on July 13 and 14, 1999, and was the only tested unit at this facility. Simultaneous measurements were conducted at the inlet and outlet of the Scrubber/Baghouse. Mercury emissions were speciated into elemental, oxidized, particle-bound and total mercury using the Ontario-Hydro test method. Fuel samples were also collected concurrently with Ontario-Hydro samples in order to determine fuel mercury content.

1.2 KEY PERSONNEL

The key personnel who coordinated the test program and their telephone numbers are:

- Braun Intertec Project Manager - Bruce Randall (612) 833-4653
- BEPC Air Quality Program Coordinator - Jerry Menge (701) 223-0441
- BEPC AVS Plant Contact/Process Monitor - Cris Miller (701) 873-4545

2.0 PLANT AND SAMPLING LOCATION DESCRIPTIONS

2.1 PROCESS DESCRIPTION

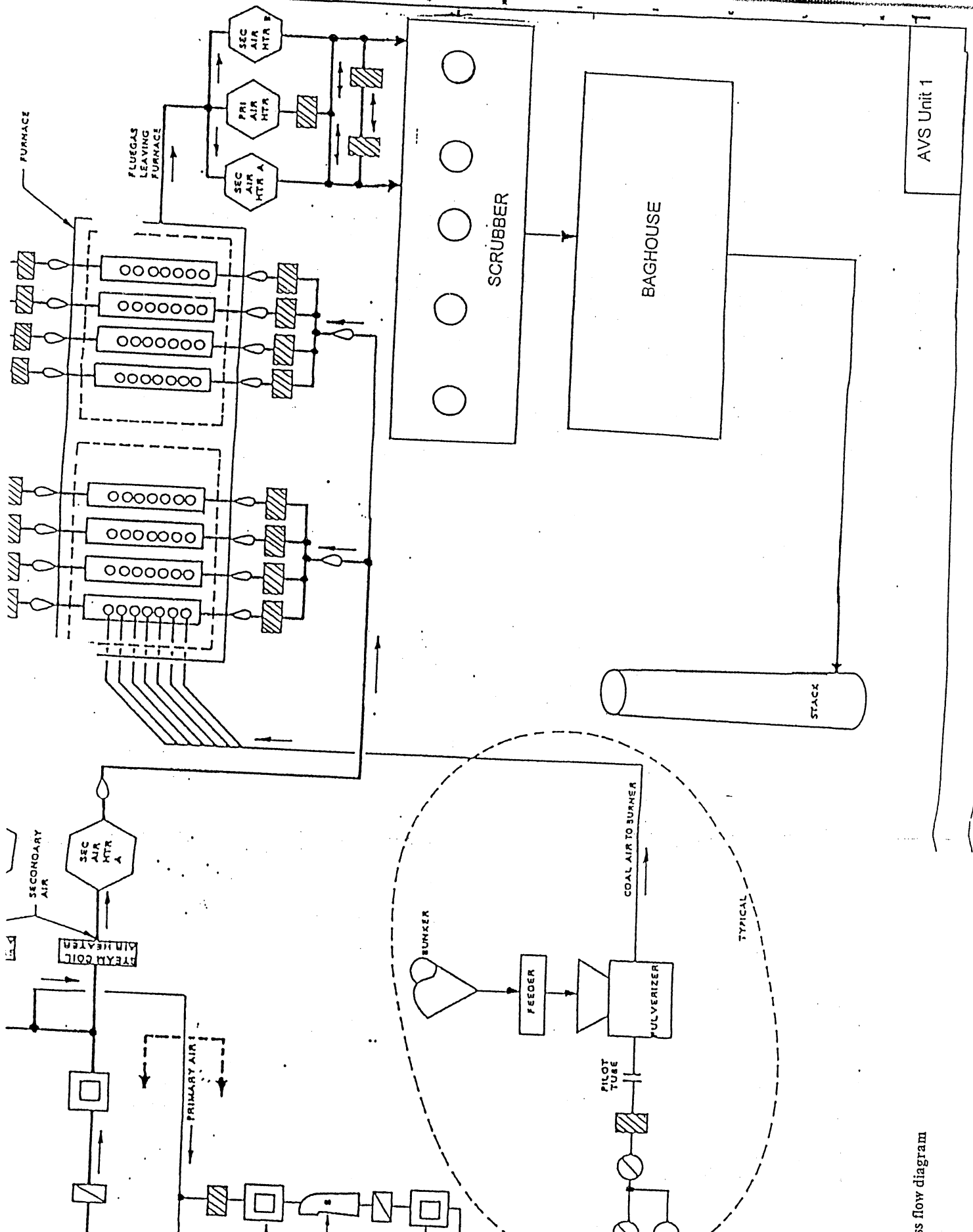
Figure 2-1 illustrates the basic operational steps for this coal-fired steam generator. The steps are:

1. Lignite coal is delivered from the Coteau mine by conveyor belt.
2. The coal is conveyed to the plant where it is pulverized.
3. The coal is combusted in the furnace using primary and secondary air.
4. The flue gas enters the scrubber and is sprayed with a mixture of lime and fly ash slurry.
5. The flue gas enters the baghouse where particulates are removed.
6. The gas exits the baghouse and exits the stack.

The Antelope Valley Station Unit B1 consists of a Combustion Engineering tangential lignite coal-fired boiler. The unit has a net electric generation capacity of 450 MW. During the test, the average gross electric generation was 467.6 MW.

Lignite is provided to the plant by the Coteau Mine and delivered by conveyor belt. The coal is conveyed to the plant coal bunkers, where it is fed to the pulverizers. From the pulverizers, coal is blown into the furnace using primary air as the conveyor and secondary air as fuel combustion air. During the test, the average coal feed rate was 736 tons per hour (tph).

Flue gas from the unit's boiler flows to a flue gas desulfurization system (scrubber). The scrubber removes SO₂ using lime and fly ash slurry as the scrubbing agent. From the scrubber, flue gas flows through a fabric filter baghouse where fly ash and particulate matter are removed. From the baghouse, an induced draft fan pushes the flue gas into the 600-foot main stack. The flue gas enters perpendicular to the stack. Continuous Emissions Monitoring System (CEMS) equipment is located at the 300 foot level of the unit stack liner.



Process flow diagram

2.2 CONTROL EQUIPMENT DESCRIPTION

The Scrubber is a Joy-Niro dry scrubber consisting of five spray dryer atomizer (SDA) chambers. The flue gas is passed through one of the five SDA chambers in the scrubber. A slurry with 40% to 45% solids containing slaked lime and fly ash is introduced to the chamber by individual atomizers. The heat of the flue gas dries the liquid in the slurry. Particulate matter is removed by a reverse air fabric filter baghouse, manufactured by the Western Precipitation division of Joy Manufacturing Company.

Table 2-1 presents a summary of the average operating parameters for the Scrubber/Baghouse during the test.

Table 2-1: Scrubber/Baghouse Operating Parameters

<u>Parameter</u>	<u>Normal Range</u>
Volumetric Flow Rate	1.311 mmscfm
Inlet SO ₂ Concentration	747 ppm
Outlet SO ₂ Concentration	124 ppm
Outlet SO ₂ Mass Flow Rate	1640 lb/hr
Modules in service	5 SDA Chambers
% Slurry Solids	43%
Slurry Feed Rate	489.9 gpm
Scrubber Inlet Temp	291°F
Scrubber Outlet Temp	186°F
Baghouse ΔP	8.6" H ₂ O
Lime to Sulfur Ratio	1.13

2.3 FLUE GAS SAMPLING LOCATIONS

Emissions sampling was conducted at: (1) the inlet to the scrubber/baghouse, and (2) the main stack. Figures 2-2 and 2-3 are schematics of these sampling locations.

2.3.1 Scrubber/Baghouse Inlet. See Figure 2-2. Also BEPC Drawings 5500-002-166, 5500-002-125, 5500-002-126 and 5500-002-129. The inlet duct is 26 feet wide and 23 feet deep, and is equipped with 8 sample ports, consisting of six inch threaded pipe nipples (with caps), approximately two feet long.

Due to its proximity to the manifold, the inlet location does not meet the port placement criteria of EPA Method 1. The Ontario-Hydro Method (Section 10.1.5) requires that sample be collected for not less than two hours, and not more than three hours. The method further requires that sample be collected for at least five minutes at each traverse point. Per the "Electric Utility Steam Generating Unit Mercury Emissions" web page, the furthest traverse point into the duct was sixteen feet from the top of the duct.

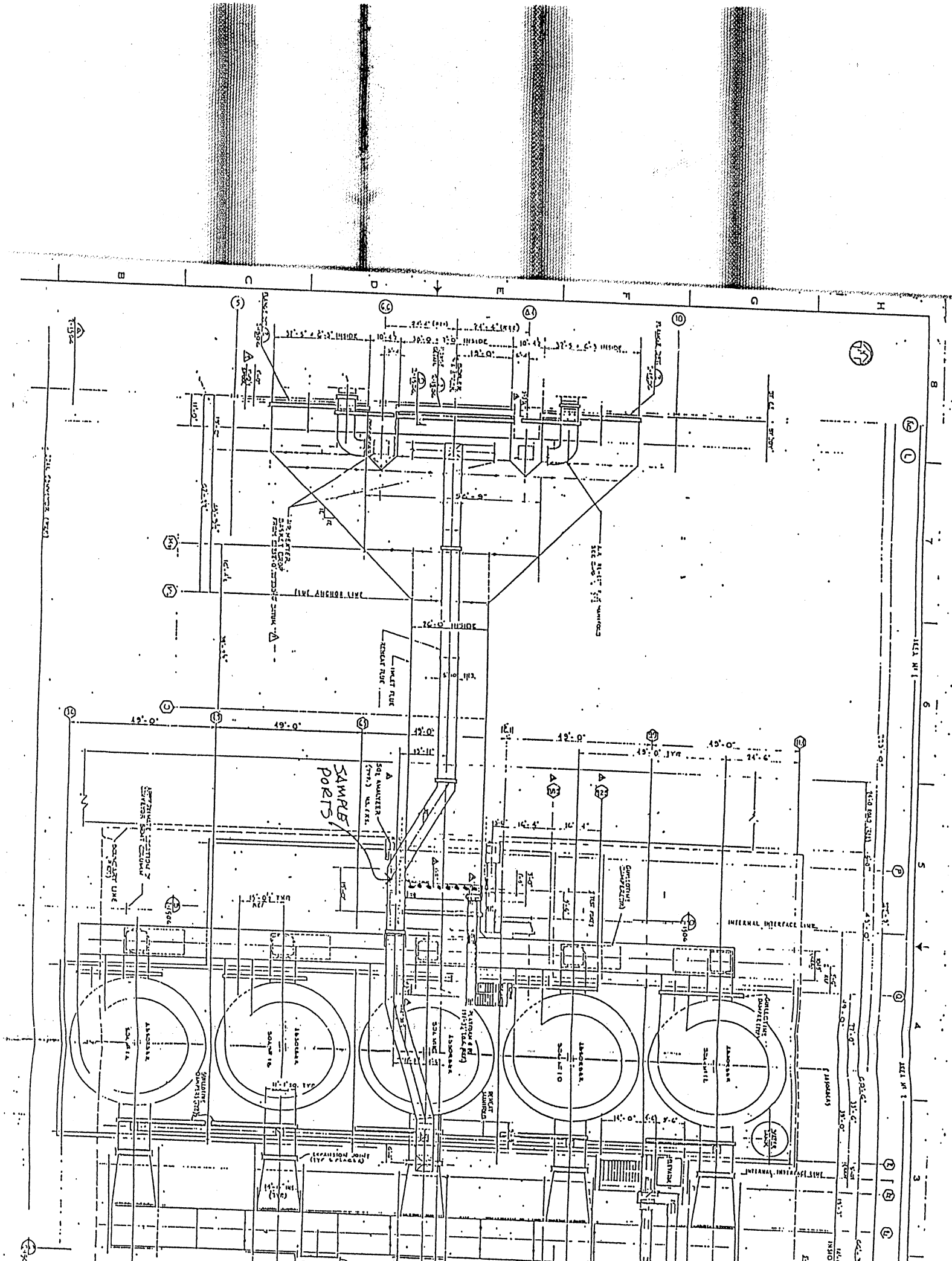
Sampling was originally planned at three traverse points in each of the eight ports (twenty-four total points), for five minutes per point. Due to an obstruction on one side of the duct, and the proximity of one port to the edge of the duct on the other side, sampling was only practical from five of the eight ports. In each port, sample was collected for eight minutes per point at the following points:

<u>Traverse Point Number</u>	<u>Distance From Inside Top Wall (inches)</u>
1	38.4
2	115.2
3	192.0

The inlet sampling location did not meet the criteria of Method 1. Per the "Electric Utility Steam Generating Unit Mercury Emissions" web page, no modifications to the sampling procedure will be made, since ". . . (a) mercury is primarily in the gaseous phase and is not impacted by uncertainties in the gas flow and isokinetic sampling rate, and (b) stratification of mercury species is not expected."

- 2.3.2 Main Stack. See Figure 2-3. The diameter of the main stack at the sample location is 308.4 inches. The main stack is equipped with four 6-inch sample ports. The sample ports are located 232.3 feet (9 duct diameters) downstream of the flue gas entry to the stack, and 300 feet (11.7 duct diameters) upstream of the stack exit. Sampling was conducted at a total of twelve traverse points, three in each of the four ports. In each port, sample was collected for ten minutes per point, at the following points:

<u>Traverse Point Number</u>	<u>Distance From Inside Wall (inches)</u>
1	13.6
2	45.0
3	91.0



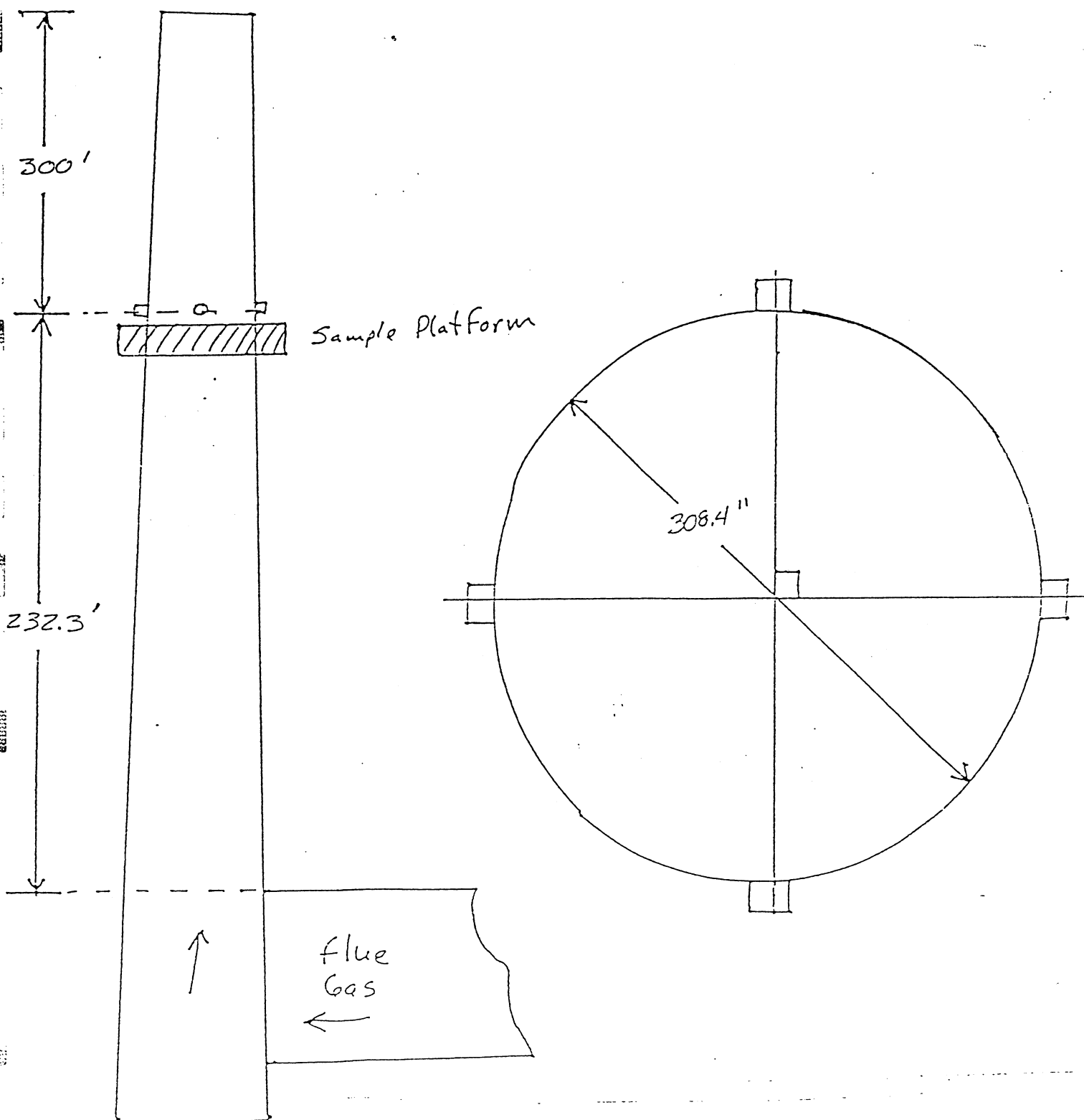


Figure 2-3: Schematic of the AVS Unit B1 Main Stack Sampling Location

2.4 FUEL SAMPLING LOCATION

Fuel samples were collected at the inlet to C Volumetric Coal Feeder by diverting the fuel to a sampling container. The sample at this point was expected to be homogeneous.

3.0 SUMMARY AND DISCUSSION OF TEST RESULTS

3.1 OBJECTIVES AND TEST MATRIX

The purpose of the test program was to quantify mercury emissions from this unit. This information will assist the EPA Administrator in determining whether it is appropriate and necessary to regulate emissions of Hazardous Air Pollutants (HAPs) from electric utility steam generating units. The specific objectives, in order of priority were:

- Compare mass flow rates of mercury at the three sampling locations (fuel, inlet to and outlet from the scrubber/baghouse).
- Obtain process and control equipment operating data during the test period: Process - Gross MW, CO₂ based heat input (MMBtu/hr) and coal feed rate (tons per hour). Control Equipment - exhaust gas volumetric flow rate (SCFH), inlet and outlet SO₂ concentrations (ppm), number of SDA modules in service, % solids in the slurry feed, slurry feed rate (gal/min), scrubber inlet and outlet temperature, baghouse ΔP , lime to SO₂ removal ratio.

Table 3-1 presents the sampling and analytical matrix and sampling log.

Table 3-1: Sampling Matrix

Run No. Date	Sample Type	Test Method	Location/Clock Time/Sampling Time	
			Inlet	Outlet
1 7/13/99	Speciated Mercury	Ontario Hydro	1254-1512 120	1254-1513 120
2 7/14/99	Speciated Mercury	Ontario Hydro	0756-1016 120	0756-1015 120
3 7/14/99	Speciated Mercury	Ontario Hydro	1120-1340 120	1120-1339 120

3.2 FIELD TEST CHANGES AND PROBLEMS

- 3.2.1 Inlet Sample Location. As described in 2.3.1, it was not possible to sample at the inlet sample location as was initially planned. For the reasons described in Section 2.3.1, it is not anticipated that this change led to any bias in the determination of mercury concentrations.
- 3.2.2 Hydroxylamine Sulfate Solution. On July 9, 1999, Bruce Randall received a telephone call from the Energy and Environmental Research Center. The caller informed Mr. Randall that the recipe for this solution was to be revised such that equal amounts of Hydroxylamine Sulfate and Sodium

Chloride were utilized. Mr. Randall verbally confirmed this change with Mr. Bill Grimley of EPA. This change was incorporated and utilized.

3.3 PRESENTATION OF RESULTS

- 3.3.1 Mercury Mass Flow Rates. The mass flow rates of Mercury determined at each sample location are presented in Table 3-2.

Table 3-2: Summary of Results

Sample Location	Elemental Mercury (gram/hr)	Oxidized Mercury (gram/hr)	Particle-Bound Mercury (gram/hr)	Total Mercury (gram/hr)
<u>Fuel</u>				
Run 1				41.7
Run 2				46.5
Run 3				35.9
Average				41.4
<u>Scrubber Baghouse Inlet</u>				
Run 1	14.64	0.72	< 0.295	15.36
Run 2	14.52	0.77	< 0.390	15.29
Run 3	14.07	0.29	< 0.293	14.36
Average	14.41	0.59	< 0.326	15.00
<u>Main Stack</u>				
Run 1	0.30	0.41	< 0.010	0.71
Run 2	13.13	1.27	0.038	14.44
Run 3	11.18	0.51	0.038	11.73
Average All Runs	8.20	0.73	< 0.029	8.96
Average Runs 2 & 3	12.16	0.89	0.038	13.09

The mass flow rate of speciated mercury measured during the first sample run at the main stack is significantly less than the subsequent two runs. The cause of this difference is not known. All field QA/QC checks were acceptable for the first run. The F_o factor and duct gas moisture content determined during this run were consistent with the subsequent two runs. If the results of the first sample run are not utilized in calculating average mass flow rates, the average of runs 2 and 3 are also presented in Table 3-2.

- 3.3.2 Comparison of Volumetric Flow Rate. Volumetric flow rate is a critical factor in calculating mass flow rates. Ideally, the volumetric flow rate (corrected to standard pressure and temperature) measured at the inlet to the control device should be the same as that measured at the stack, which should be the same as that measured by the CEMS. As can be seen in Table 3-3, agreement between the three locations on a thousand standard cubic foot per minute basis (KSCFM) was quite good.

Table 3-3: Comparison of Volumetric Flow Rate Data

	Inlet KACFM/KSCFM/KDSCFM	Stack KACFM/KSCFM/KDSCFM	CEMS KACFM/KSCFM
Run 1	2,360/1,506/1,275	1,767/1,390/1,128	1,760/1,310
Run 2	2,304/1,484/1,262	1,753/1,394/1,138	1,741/1,317
Run 3	2,273/1,451/1,236	1,710/1,352/1,103	1,739/1,305
Average	2,312/1,480/1,258	1,743/1,379/1,123	1,747/1,311

The measured volumetric flow rate (KSCFM) at the inlet was approximately 7% higher than that measured at the stack. The measured volumetric flow rate at the stack (KSCFM) was approximately 5% higher than that determined by the CEMS. Percent differences of this magnitude should be considered to be very good, and indicate that mass flow rates of mercury calculated based on this data should be representative.

There is a difference in volumetric flow rate (KDSCFM) between the inlet and the stack of approximately 11%. However, this is not a valid comparison, since moisture is added to the gas stream during the scrubbing process. The average fractional moisture content (Bws) of the inlet gas stream was 0.151, while the average Bws at the stack was 0.186. If the average inlet volumetric flow rate (KSCFM) is corrected to the same fractional moisture content as the stack, the average inlet volumetric flow rate (KDSCFM) becomes 1,206. This value differs from the stack KDSCFM by approximately 7%, which is consistent with difference in flow rate at standard temperature and pressure.

- 3.3.3 Individual Run Results. A detailed summary of results for each sample run at the inlet and main stack are presented in Tables 3-4 and 3-5, respectively.

Table 3-4: Inlet Individual Run Results

Parameter	Run 1	Run 2	Run 3	Average
Sample Date	7/13/99	7/14/99	7/14/99	
Clock Time	1254-1512	0756-1016	1120-1340	
Sample Time	120	120	120	120
Average Duct Temperature (°F)	309	303	310	307
Average Duct Velocity (ft/s)	65.6	64.2	63.3	64.4
Moisture Content (%vol)	15.4	15.0	14.8	15.1
CO ₂ Content (%vol dry)	5.4	5.4	5.4	5.4
O ₂ Content (%vol dry)	14.4	14.5	14.4	14.4
F _o	1.076	1.069	1.076	1.074
Wet Molecular Weight (g/g-mole)	28.60	28.66	28.67	28.64
Volume Flow Rate (ACFM)	2360200	2303500	2272600	2312100
Volume Flow Rate (SCFM)	1506700	1484100	1450600	1480500
Volume Flow Rate (DSCFM)	1275200	1261700	1236300	1257800
Coal Feed Rate (ton/hr)	766	722	720	736
Coal Hg Content (mg/kg, dry basis)	0.060	0.071	0.055	0.062
Sample Volume (dscf)	77.834	77.650	75.891	77.125
Net Elemental Hg (µg)	14.90	14.90	14.30	14.70
Net Oxidized Hg (µg)	0.73	0.79	0.30	0.61
Net Particle-Bound Hg (µg)	< 0.300	< 0.400	< 0.300	< 0.333
Total Hg (µg)	15.63	15.60	14.52	15.31
Elemental Hg ER (gram/hr)	14.64	14.52	14.07	14.41
Oxidized Hg ER (gram/hr)	0.72	0.77	0.29	0.59
Particle-Bound Hg (gram/hr)	< 0.295	< 0.390	< 0.293	< 0.326
Total Hg (gram/hr)	15.36	15.29	14.36	15.00
Sample Percentage of Isokinetic (%)	98.5	99.3	99.0	98.9

Table 3-5: Main Stack Individual Run Results

Parameter	Run 1	Run 2	Run 3	Average
Sample Date	7/13/99	7/14/99	7/14/99	
Clock Time	1254-1513	0756-1015	1120-1339	
Sample Time	120	120	120	120
Average Duct Temperature (°F)	186	180	184	183
Average Duct Velocity (ft/s)	56.8	56.3	54.9	56.0
Moisture Content (%vol)	18.9	18.4	18.4	18.6
CO ₂ Content (%vol dry)	6.0	6.0	5.6	5.9
O ₂ Content (%vol dry)	13.8	13.9	14.2	14.0
F _o	1.080	1.072	1.077	1.076
Wet Molecular Weight (g/g-mole)	28.10	28.17	28.19	28.15
Volume Flow Rate (ACFM)	1767200	1752900	1709500	1743200
Volume Flow Rate (SCFM)	1390300	1394300	1352200	1378900
Volume Flow Rate (DSCFM)	1127600	1137700	1102800	1122700
Coal Feed Rate (ton/hr)	766	722	720	736
Coal Hg Content (mg/kg, dry basis)	0.060	0.071	0.055	0.062
Sample Volume (dscf)	65.143	65.478	64.535	65.052
Net Elemental Hg (µg)	0.29	12.60	10.90	7.93
Net Oxidized Hg (µg)	0.39	1.22	0.50	0.70
Net Particle-Bound Hg (µg)	< 0.01	0.037	0.037	< 0.028
Total Hg (µg)	0.68	13.86	11.44	8.63
Elemental Hg ER (gram/hr)	0.30	13.13	11.18	8.20
Oxidized Hg ER (gram/hr)	0.41	1.27	0.51	0.73
Particle-Bound Hg (gram/hr)	< 0.010	0.038	0.038	< 0.029
Total Hg (gram/hr)	0.71	14.44	11.73	8.96
Sample Percentage of Isokinetic (%)	99.1	98.7	100.3	99.4

3.3.4 Process Operating Data. The process operating data collected during the tests is presented in Table 3-6.

Table 3-6: Process Operating Data

Parameter	Run 1	Run 2	Run 3	Average
Date	7/13/99	7/14/99	7/14/99	
Start-End Time	1254-1513	0756-1015	1120-1340	
Volume Flow Rate (KACFM)	1,760	1,741	1,739	1,747
Volume Flow Rate (KSCFM)	1,310	1,317	1,305	1,311
Inlet SO ₂ (ppm wet)	719	760	763	747
Stack SO ₂ (ppm wet)	129	119	124	124
Stack SO ₂ (lb/hr)	1,640	1,560	1,721	1,640
# SDA Modules	5	5	5	5
% Slurry Solids	43.1	42.9	43.0	43.0
Slurry Feed Rate (gpm)	483.4	485.0	501.2	489.9
Inlet Temperature(°F)	299	285	290	291
Stack Temperature (°F)	189	183	186	186
Baghouse ΔP ("H ₂ O)	8.5	8.6	8.7	8.6
Gross Megawatts	466	467	470	468
Lime/Sulfur Ratio	1.23	1.05	1.10	1.13
Stack NO _x (ppm wet)	204	213	212	210
Stack NO _x (lb/MMBtu)	0.392	0.319	0.411	0.374
Stack CO ₂ (% vol wet)	11.95	11.83	11.79	11.86
Stack % Opacity (6 min avg)	5.75	5.44	5.40	5.53
Coal Feed Rate (ton/hr)	766	722	720	736
SO ₂ Removal (%)	82.1	83.8	83.7	83.2
Heat Input - CO ₂ based MMBtu	5054.7	5012.0	5077.9	5,048.2

4.0 SAMPLING AND ANALYTICAL PROCEDURES

4.1 TEST METHODS

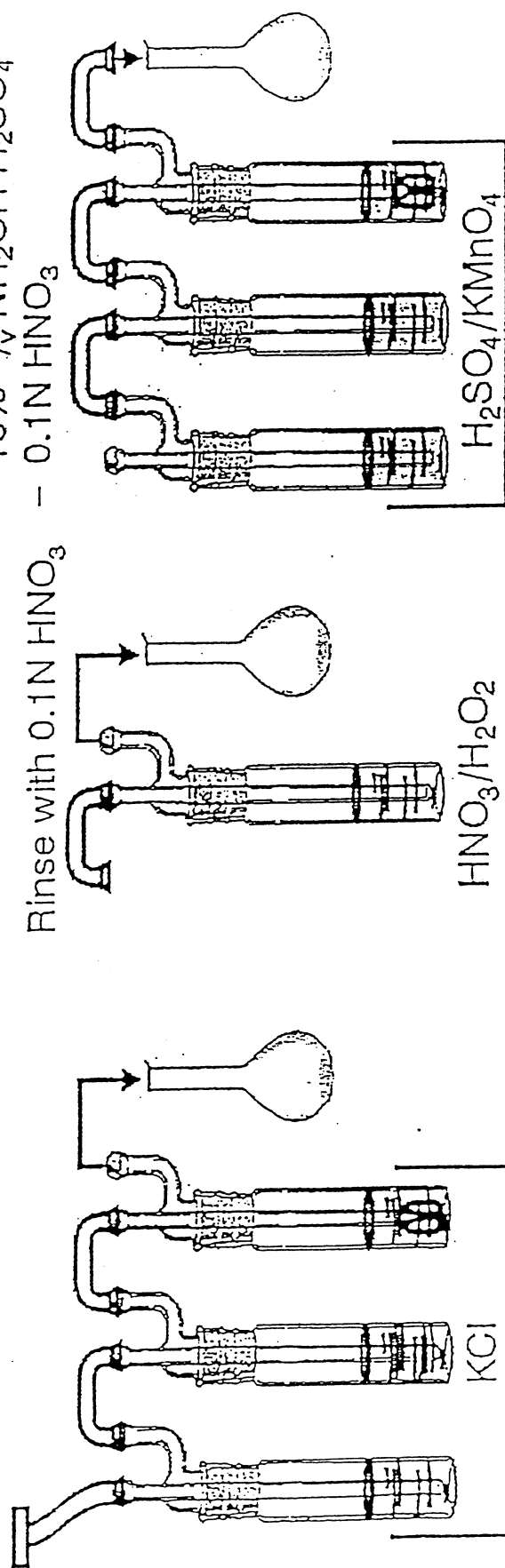
- 4.1.1 Speciated mercury emissions were determined via the draft "Standard Test Method for Elemental, Particle-Bound, and Total Mercury in Flue Gas Generated from Coal-Fired Stationary Sources (Ontario-Hydro Method)", dated April 8, 1999. Any revisions to this test method issued after April 8, 1999 but before July 1, 1999 were incorporated. The change in formula for the Hydroxylamine Sulfate recovery solution described in Section 3.2.2 of this report was the only change from the procedures proposed in the Site Specific Test Plan for this project.

The in-stack filtration (Method 17) configuration was utilized at the inlet location. The out-of-stack filtration (Method 5) configuration was utilized at the main stack. Figures 4-1 and 4-2 are schematics of the Ontario-Hydro sampling trains.

Figure 4-3 illustrates the sample recovery procedure. The analytical scheme was per Section 13.3 of the Ontario-Hydro Method.

DRAFT

1. Rinse filter holder and connector with 0.1N HNO_3 .
2. Add 5% w/v KMnO_4 to each impinger bottle until purple color remains.
3. Rinse with 10% v/v HNO_3 .
4. Rinse with a very small amount of 10% w/v $\text{NH}_2\text{OH}\cdot\text{H}_2\text{SO}_4$ if brown residue remains.
5. Final rinse with 10% v/v HNO_3 .



Rinse All U-Tubes with 0.1N HNO_3

EERC-DL16139.CDR

Figure 4-3: Sample Recovery Scheme for Ontario-Hydro Method Samples

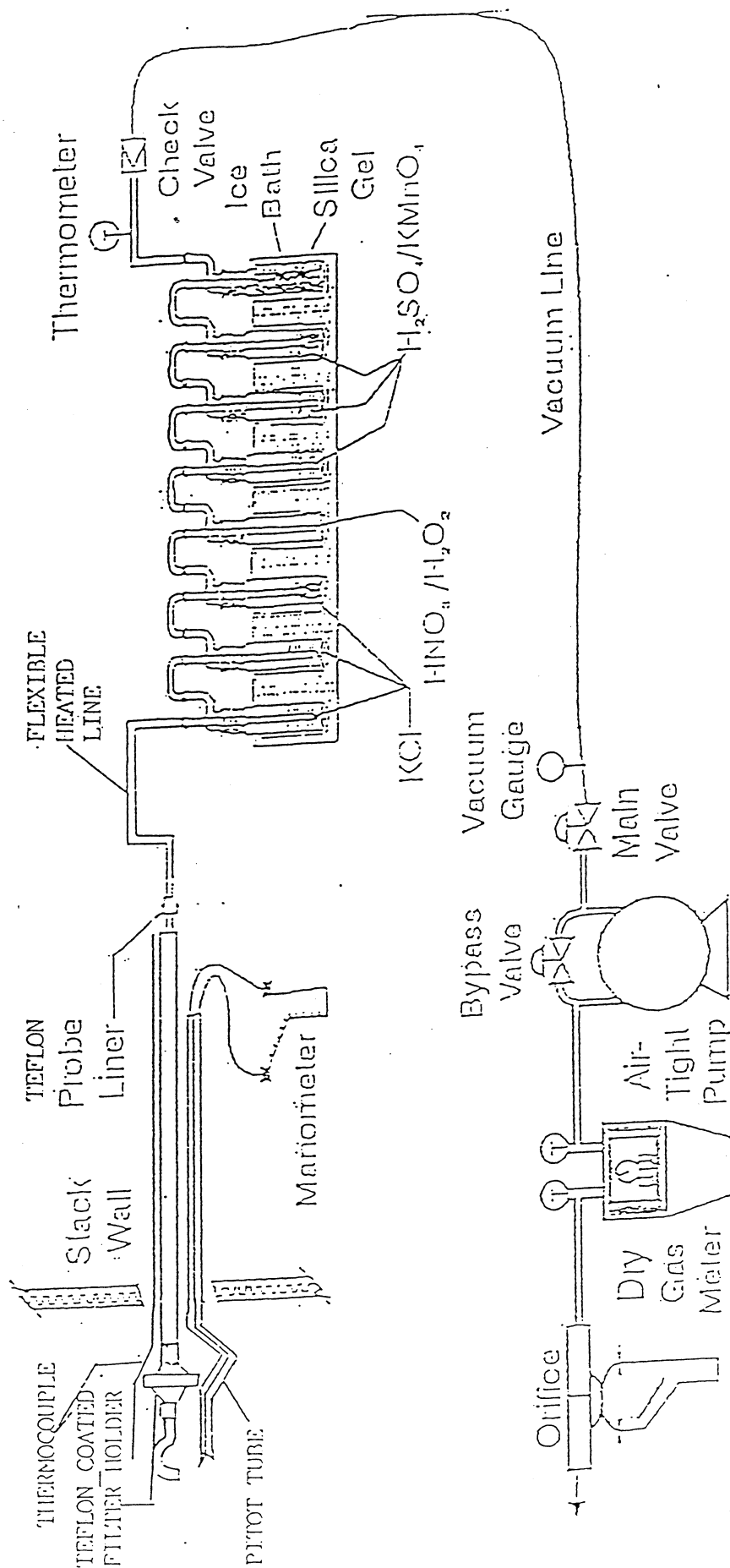


Figure 4-1: Ontario-Hydro Sampling Train (Method 17 Configuration)

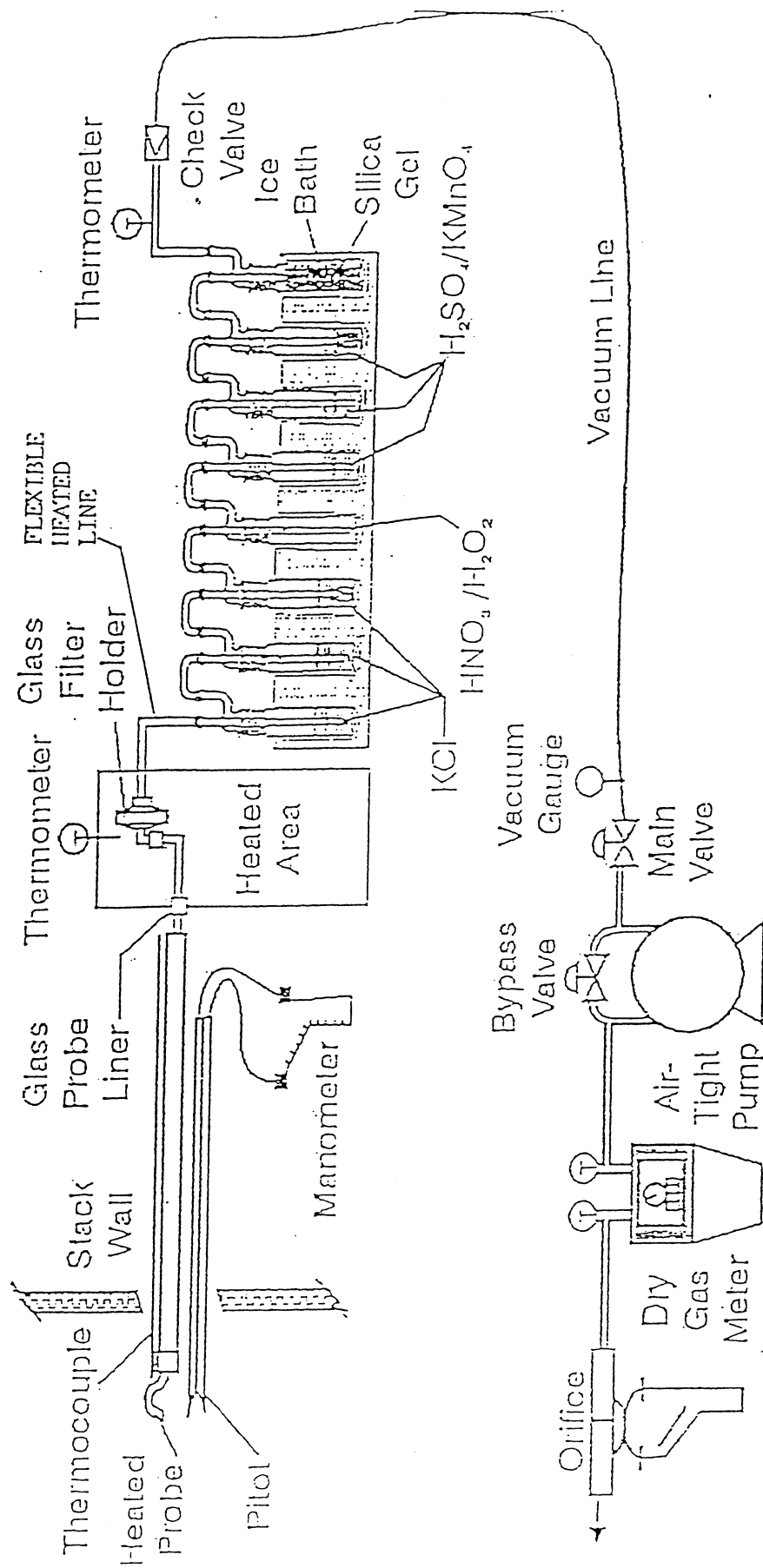


Figure 4-2: Ontario-Hydro Sampling Train (Method 5 Configuration)

- 4.1.2 Fuel samples were collected by composite sampling. Three samples were collected at equally spaced intervals during each speciated mercury sampling run. Each set of three samples was composited into a single sample for each sample run. Sample analysis was conducted according to Method 7471A.

4.2 PROCEDURES FOR OBTAINING PROCESS DATA

Mr. Cris Miller was responsible for obtaining process operating data. The process data presented in Table 3-6 was continuously monitored by the facility computerized control system and/or the Unit B1 CEMS. Process data was averaged over the course of each sample run. All instruments used to collect process data are routinely calibrated according to BEPC AVS procedures.

5.0 INTERNAL QA/QC ACTIVITIES

5.1 QA/QC PROBLEMS

The only QA/QC problem that occurred during the tests was that a detectable amount of Mercury was found in the blank train collected at the inlet location. 0.19 micrograms of Mercury was found in the KCl impingers. The Mercury content of all other blank train sample fractions at both the inlet and the main stack was consistent with that found in reagent blanks. The cause of this anomaly is not known.

5.2 QA AUDITS

5.2.1 Reagent Blanks. As required by the method, blanks were collected for all reagents utilized. The results of reagent blank analysis are presented in Table 5-1.

Table 5-1: Reagent Blank Analysis

Container #	Sample Fraction	Contents	Mercury (µg)	Detection Limit (µg)
C7/C12	Front-half	0.1N HNO ₃ /Filter	<0.010	0.010
C8	1 N KCl	1 N KCl	<0.030	0.030
C9	HNO ₃ /H ₂ O ₂	HNO ₃ /H ₂ O ₂	<0.25	0.010
C10	KMnO ₄ /H ₂ SO ₄	KMnO ₄ /H ₂ SO ₄	<0.030	0.030

5.2.2 Blank Trains. As required by the method, blank trains were collected at both the inlet and stack sampling locations. These trains were collected on 7/13/99. The results of blank train analysis are presented in Table 5-2.

Table 5-2: Blank Train Analysis

Container #	Sample Fraction	Contents	Mercury (µg)	Detection Limit (µg)
IB C01/C02	Front-half	Filter/front-half rinse	<0.040	0.010
SB C01/C02	Front-half	Filter/front-half rinse	<0.010	0.010
IB C03	KCl impingers	Impingers/rinse	0.085	0.030
SB C03	KCl impingers	Impingers/rinse	<0.030	0.030
IB C04	HNO ₃ -H ₂ O ₂ impingers	Impingers/rinse	<0.25	0.010
SB C04	HNO ₃ -H ₂ O ₂ impingers	Impingers/rinse	<0.25	0.010
IB C05	KMnO ₄ /H ₂ SO ₄ impingers	Impingers/rinse	<0.030	0.030
SB C05	KMnO ₄ /H ₂ SO ₄ impingers	Impingers/rinse	<0.030	0.030

5.2.3 Field Dry Test Meter Audit. The field dry test meter audit described in Section 4.4.1 of Method 5 was completed prior to the test. The results of the audit are presented in Table 5-3.

Table 5-3: Field Meter Audit

Meter Box Number	Pre-Audit Value	Allowable Error	Calculated Yc	Acceptable
81231	1.003	$0.9729 < Y_c < 1.0331$	1.0074	Yes
38758	1.005	$0.9749 < Y_c < 1.0352$	1.0062	Yes

